

**From:** [Barry](#)  
**To:** [UICRegulations@DOC](mailto:UICRegulations@DOC)  
**Cc:** [Ex. 6 - Personal Privacy](#)  
**Subject:** Comments On Draft UIC Regulations  
**Date:** Tuesday, February 16, 2016 2:33:04 PM  
**Attachments:** [UIC Update Discussion Draft Regulations.pdf](#)  
[Comments on Draft Regulations to DOGGR 2-16.docx](#)

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Greetings:

Attached please find comments submitted in opposition of the draft UIC regulations issued 1-21-16. In my 36 years of practicing the Petroleum Engineering trade, I've never encountered a set of regulations as malignantly oppressive and poorly conceived as those proposed by the DOGGR. But they fall in line neatly with the recent years of scandals, purges, and corruption exhibited by this once respected institution.

I didn't spend years learning and honing my engineering skills to waste them on worthless garbage like this, rather than in the service of finding and producing abundant cheap energy to cleanly and safely power modern civilization. I could write chapters on the technical errors, shortcomings and inappropriate assumptions contained in this draft. But I've still got a few useful things to do today, and have therefore mostly confined my comments to the worst problems with this draft, which are philosophical, rather than technical.

When governance shows contempt for the rule of law, for fairness, efficiency, humility, and for due process, the governed will quickly learn contempt for governance. A cycle that is already well advanced.

Sincerely

Barry Hanson  
Petroleum Engineering Consultant

[Ex. 6 - Personal Privacy](#)

# **UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS**

## **PRE-RULEMAKING DISCUSSION DRAFT**

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### **CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES**

#### **Subchapter 1. Onshore Well Regulations**

#### **Article 2. Definitions**

##### **1720.1. Definitions**

The following definitions are applicable to this subchapter:

(a) “Area of review” means an area that includes a radius around each injection well that is part of an underground injection project, the radius being the greater of (1) or (2).

(1) The radius shall be at least the calculated lateral distance in which the pressures in the injection zone may cause the migration of the injection fluid or the formation fluid out of the intended zone of injection; and

(2) The radius shall be at least:

(A) One quarter mile for an injection well that is not a cyclic steam; or

(B) 300 feet for an injection well that is a cyclic steam well.

(b) “Surface expression” means a flow of fluid or material to the surface that is not through a well and that is caused by injection operations.

(c) “Surface expression containment measure” means an engineered measure undertaken in accordance with all state and local requirements to contain or collect the fluids from a surface expression, including but not limited to subsurface collection systems, collection wells, cisterns, culverts, French drains, collection boxes, or gas hoods or other gas collection system.

(d) “Freshwater” means water that contains 3,000 TDS or less.

(e) "Underground injection project" means sustained or continual injection into one or more wells over an extended period in order to add fluid to a zone for the purpose of enhanced oil recovery, disposal, or storage. Examples of underground injection projects include waterflood injection, steamflood injection, cyclic steam injection, injection disposal, and gas storage projects.

(f) "Underground source of drinking water" or "USDW" mean an aquifer or its portion that contains fewer than 10,000 TDS and has not received an aquifer exemption aquifer exemption proposed by the Division and approved pursuant to the Code of Federal Regulations, title 40, section 144.7.

#### AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

### **Article 3. Requirements**

#### **1724.6. Approval of Underground Injection and Disposal Projects**

(a) A Project Approval Letter shall ~~Approval must be obtained from this the~~ Division before any injection occurs as part of an underground injection project. ~~subsurface injection or disposal project can begin. This includes all EPA Class II wells and air and gas injection wells.~~ The operator requesting approval for such a project must provide the appropriate Division district deputy with the data specified in Section 1724.7 and any data that, in the judgment of the Supervisor, are pertinent and necessary for the proper evaluation of the proposed project.

(b) The Project Approval Letter shall specify the location and nature of the underground injection project, as well as the conditions of the Division's approval. Modification of an underground injection project is subject to approval by the Division and shall be noted in either an addendum to the Project Approval Letter or a revised Project Approval Letter. Underground injection project operations shall not occur unless consistent with the terms and conditions of a current Project Approval Letter. Regardless of the contents of a Project Approval Letter, injection suspended under Section 1724.10(l) shall not resume without subsequent approval from the Division.

(c) The Division will review underground injection projects to verify adherence to the terms and conditions of the Project Approval Letter, and will periodically review the terms and conditions of the Project Approval Letter to ensure that they effectively

prevent damage to life, health, property, and natural resources. Approval of an underground injection project is at the Division's ongoing discretion and a Project Approval Letter is subject to suspension, modification, or rescission by the Division.

(d) If the Division determines that operation of an underground injection project is inconsistent with the terms and conditions of a current Project Approval Letter, or otherwise poses a threat to life, health, property, or natural resources, then upon written notice from the Division injection operations shall cease immediately, or as soon as it is safe to do so.

(e) Within 60 days after transfer of an underground injection project to a new operator, the new operator shall meet with the Division staff to ensure complete understanding of the parameters and conditions of the Project Approval Letter.

Note: Authority cited: Section 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

#### **1724.7. Project Data Requirements**

~~—(Note: See Section 1724.8 for special requirements for cyclic steam projects, and Section 1724.9 for supplementary requirements for gas storage projects.)~~

~~The data required to be filed with the district deputy include the following, where applicable:~~

(a) An underground injection project shall be supported by data filed with the Division that demonstrates to the Division's satisfaction that injected fluid will be confined to the approved zone or zones of injection and that the underground injection project will not cause damage to life, health, property, or natural resources. The operator shall ensure that the data are current and account for all changes to the setting and operation of the project. The data filed with the Division shall include the following:

(1) ~~(a)~~ An engineering and geological study demonstrating that injected fluid will not migrate out of the approved zone or zones through another well, geologic structure, faults, fractures, or fissures, or holes in casing, including but not limited to:

(A) ~~(1)~~ Statement of primary purpose of the project.

(B) ~~(2)~~ Reservoir characteristics of each injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations. The scope of the geologic characterization shall encompass the intended reservoir rock and

sealing mechanisms, the vertical interval above and below the intended reservoir, areas where fluid could potentially migrate, and the areas adjacent to the intended reservoir where potential entrapment of migrated fluid could occur.

~~(C) (3)~~ Reservoir fluid data for each injection zone, such as oil gravity and viscosity, water quality, presence and concentrations of non-hydrocarbon components in the associated gas (i.e. hydrogen sulfide), and specific gravity of gas.

~~(D)~~ A map of the area of review showing the location and status of all wells within and adjacent to the boundary of the area of review. The wellbore path of directionally drilled wells shall be shown, with indication of the interval penetrating the injection zone of the underground injection project.

~~(E) (4)~~ Casing diagrams, including cement plugs, and actual or calculated cement fill behind casing all data specified in Section 1724.7.1, of all idle, plugged and abandoned, or deeper zone-producing wells that are within the area of review and that are in the same or a deeper zone as the injection project, including directionally drilled wells that intersect the area of review in the same or deeper zone affected by the project, and evidence that plugged and abandoned. The casing diagrams must demonstrate that the wells in the area will not be a potential conduit for fluid to migrate outside of the approved zone of injection or otherwise have an adverse effect on the project or cause damage to life, health, property, or natural resources. At a minimum, the casing diagrams must demonstrate that:

(i) Plugged and abandoned wells have cement across all perforations and extending at least 500 feet, if shown by calculation, or 100 feet, if shown by cement bond log or other method approved by the Division, above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, the intended zone of injection, or the oil and gas zone; and

(ii) Wells that are not plugged and abandoned and that have not been used for injection or production for more than two years have cement plugs across all hydrocarbon zones, the base of the USDW interface, and the base of the freshwater interface.

(F) Identification of all wells within the area or review that do not penetrate the injection zone of the underground injection project, including description of the total depth of the well and the estimated top of the injection zone below the well.

(G) Wells completed in or penetrating through the intended injection zone shall be evaluated for containment assurance for the design of injection operation volumes, pressure, and flow rates. The operator should identify, and the Division confirm, wells

which may require integrity testing or well logging in order to meet the integrity demonstration. The Division may select plugged and abandoned wells to be re-entered, examined, re-plugged and abandoned, or monitored to manage identified containment assurance issues prior to approval of injection.

~~(H) (5)~~ The planned well-drilling and plugging and abandonment program to complete the project, including a flood-pattern map, if applicable, showing all injection, production, and plugged and abandoned wells, and unit boundaries.

~~(I)~~ Maps of the locations of underground disposal horizons, mining, and other subsurface industrial activities not associated to oil and gas production within the area of review.

~~(2) (b)~~ A geologic study, including but not limited to:

~~(A) (1)~~ Structural contour map drawn on a geologic marker at or near the top of each injection zone in the project area, indicating faults and other lateral containment features.

~~(B) (2)~~ Isopachous map of each injection zone or subzone in the project area.

~~(C) (3)~~ At least one geologic cross section through at least one injection well in the project area.

~~(D) (4)~~ Representative electric log to a depth below the deepest producing zone (if not already shown on the cross section), identifying all geologic units, formations, USDW aquifers, freshwater aquifers, and oil or gas zones.

~~(3) (c)~~ An injection plan, including but not limited to:

~~(A) (1)~~ A map showing injection facilities.

~~(B) (2)~~ Maximum anticipated surface injection pressure (pump pressure) and daily rate of injection, by well.

~~(C) (3)~~ Monitoring system or method to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the ~~intended~~ approved zone or zones of injection. If groundwater monitoring is a component of the underground injection project, then documentation shall be provided of the results of the consultation with the State Water Resources Control Board or Regional Water Quality Control Board.

~~(D) (4)~~ Method of injection.

~~(E) (5)~~ List of proposed cathodic protection measures for plant, lines, and wells, if such measures are warranted.

~~(F) (6)~~ Treatment of water to be injected.

~~(G) (7)~~ Source and analysis of the injection ~~liquid~~ fluid, as specified in Section 1724.7.2.

(H) ~~(8)~~ Location and depth of each water-source well that will be used in conjunction with the project.

(4) The results of step rate tests, conducted in accordance with Section 1724.7.3, for each injection well that is part of the underground injection project. Subject to approval from the Division, this requirement may be satisfied by providing representative step rate test data from select wells within the underground injection project in order to establish a conservative ~~estimated~~ baseline fracture gradient for the entire area of the underground injection project. The Division will approve the use of an estimated baseline fracture gradient if, based on consideration of geologic, engineering, and operational factors, it is satisfied that the estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered anywhere in the area. If an estimated baseline fracture gradient is approved, a higher fracture gradient may be established for a specific well within the underground injection project, if the higher fracture gradient is supported by a well-specific step rate test conducted in accordance with Section 1724.7.3.

(5) ~~(d)~~ Copies of letters of notification sent to offset operators adjacent to the proposed project area and within the area of review.

(6) ~~(e)~~ Other data as required for large, unusual, or hazardous projects, for unusual or complex structures, or for critical wells. Examples of such data are: isogor maps, water-oil ratio maps, isobar maps, equipment diagrams, and safety programs.

(7) Identification of all injection wells that are part of the underground injection project and all production wells that are intended to be affected by the underground injection project.

(8) Any data that, in the judgment of the Supervisor, are pertinent and necessary for the proper evaluation of the underground injection project.

(b) When a new injection well is added to an underground injection project it is not necessary to duplicate data already provided to the Division, except that updated data shall be provided to the Division if conditions have changed or if more accurate data has become available.

(c) ~~(f)~~ All data filed with the Division under this section shall be submitted electronically and in paper form. All maps, diagrams and exhibits required in subdivision (a) Section 1724.7(a) through ~~(e)~~ shall be clearly labeled as to scale and purpose and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.

(d) Where it is infeasible to supply the data specified in subdivision (a), the Division may accept alternative data, provided that the alternative data demonstrates to the

Division's satisfaction that injected fluid will be confined to the approved zone or zones of injection and that the subsurface injection or disposal project will not cause damage to life, health, property, or natural resources.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

**1724.7.1. Casing Diagrams**

(a) Casing diagrams submitted under Section 1724.7(a)(1)(D) shall adhere to the following requirements:

(1) Casing diagrams shall include all of the following data:

(A) API number of the well;

(B) Ground elevation from sea level;

(C) Reference elevation (i.e. rig floor or Kelly bushing);

(D) Base of freshwater;

(E) Base of USDW;

(F) Sizes and weights of casing;

(G) Depths of shoes, stubs, and liner tops;

(H) Depths of perforation intervals, water shutoff holes, cement port, cavity shots, cuts, casing damage, and top of junk or fish left in well;

(I) Diameter and depth of hole;

(J) Cement plugs inside casings, including top and bottom of cement plug, with indication of method of determining;

(K) Cement fill behind casings, including top and bottom of cement fill, with indication of method of determining;

(L) Type and weight (density) of fluid between cement plugs;

(M) Depths and names of the formations, zones, and sand markers penetrated by the well, including the top and bottom of the zone where injection will occur;

(N) All steps of cement yield and cement calculations performed;

(O) All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job completed in each well; and



\_\_\_ (P) All of the information listed in this paragraph for all previous redrilled or sidetracked well bores.

\_\_\_ (2) Measured depth and true vertical depth shall be provided for all depths required under subdivision (a)(1).

\_\_\_ (3) Casing diagrams for directionally drilled wells, shall include a wellbore path giving both inclination and azimuth measurements.

\_\_\_ (4) Casing diagrams shall be submitted as both a graphical diagram and as a flat data set.

**AUTHORITY:**

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

**1724.7.2. Injection Fluid Analysis**

\_\_\_ (a) Injection fluid analysis required under this Article shall include testing for all of the following: total dissolved solids; metals listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A); aluminum; antimony; arsenic; barium; beryllium; boron; cadmium; calcium; chromium; cobalt; copper; iron; lead; lithium; magnesium; manganese; mercury; molybdenum; nickel; potassium; selenium; silver; sodium; strontium; thallium; vanadium; zinc; Polynuclear Aromatic Hydrocarbons including, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, benzo(a)pyrene, benzo(g,h,i)perylene, chrysene, dibenzo(a,h)anthracene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, and pyrene; radionuclides including, Gross alpha particle activity, Gross beta particle activity, Radium-226, Radium-228, Strontium-90, Tritium, and Uranium.

\_\_\_ (b) Injection fluid analysis required under this Article shall be done by a laboratory that is certified by the California Department of Public Health environmental laboratory accreditation program.

**AUTHORITY:**

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

### **1724.7.3. Step Rate Tests**

(a) Step rate tests conducted under Section 1724.7(a)(4) shall adhere to the following requirements:

(1) When a step rate test is conducted on a formation with a permeability of greater than 10 millidarcies the well must be shut in for at least 48 hour prior to the test and the time steps shall be 60 minutes.

(2) When a step rate test is conducted on a formation with a permeability of 10 millidarcies or less the well must be shut in for at least 72 hour prior to the test and the time steps shall be 90 minutes.

(3) The first three steps of the step rate test shall be below the fracture gradient.

(4) Real time downhole pressure recording shall be employed, unless an alternative has been approved by the Division.

(5) Bottom hole pressure shall be recorded at a zero injection rate for at least one full time step before the first step of the step rate test and one full time step after the last step of the step rate test.

(b) Step rate test data reported under Section 1724.7(a)(4) shall include the injection rate, bottom hole pressure, surface pressure, pump rate volume, and time recorded continuously at a rate of every one second during the step rate test. The step rate test data submitted to the Division shall be raw and unaltered.

(c) The appropriate district office shall be notified at least 24 hours in advance of conducting a step rate test under Section 1724.7(a)(4) so that Division staff may have an opportunity to witness the step rate test.

#### **AUTHORITY:**

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

### **1724.8. ~~Data Required for Cyclic Steam Injection Project Approval~~**

~~—The data required by the Division prior to approval of a cyclic steam (steam soak) project include, but are not limited to, the following:~~

~~—(a) A letter from the operator notifying the Division of the intention to conduct cyclic steam injection operations on a specific lease, in a specific reservoir, or in a particular well.~~

~~—(b) If cyclic steam injection is to be in wells adjacent to a lease boundary, a copy of a~~

~~letter notifying each offset operator of the proposed project.~~

**AUTHORITY:**

~~Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.~~

**1724.10. Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects**

(a) The appropriate Division district deputy shall be notified of any anticipated changes in an underground injection project resulting in ~~alteration of conditions originally approved~~ inconsistency with the current conditions of approval, such as: increase in size, change of injection interval, or increase in injection pressure. Such changes shall not be carried out without Division approval in accordance with Section 1724.6.

(b) Notices of intention to drill, redrill, deepen, or rework, on current Division forms, shall be completed and submitted to the Division for approval whenever a new well is to be drilled for use as an injection well and whenever an existing well is converted to an injection well, ~~even if no work is required on the well,~~ if the well is to be reworked. In addition to the notice of intention that may be required under Public Resources Code section 3203, the addition of an injection well to an underground injection project is subject to approval by the Division in accordance with Section 1724.6.

(c) An injection report on a current Division form or in a computerized format acceptable to the Division shall be filed with the Division on or before the 30th day of each month, for the preceding month.

(d) A chemical analysis of the ~~liquid-fluid~~ being injected, as specified in Section 1724.7.2, shall be made and filed with the Division at least once every two years, whenever the source of injection ~~liquid-fluid~~ is changed or an additional source is introduced, or and as requested by the Supervisor Division.

(e) An accurate, operating injection pressure gauge or pressure recording device shall be installed whenever a well is injecting available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device. A gauge or device used for injection-pressure testing, ~~which is permanently affixed to the well or any part of the injection system,~~ shall be calibrated at least every six months, or as recommended by the manufacturer. Portable gauges shall be calibrated at least every two months. Evidence of such calibration shall be available to the Division upon

request.

(f) All injection piping, valves, and facilities shall meet or exceed design standards for the maximum ~~anticipated~~ allowable injection pressure, and shall be maintained in a safe and leak-free condition.

(g) All injection wells, ~~except steam, air, and pipeline-quality gas injection wells,~~ shall be equipped with tubing and packer set immediately above the approved zone of injection ~~within one year after the effective date of this act. New or recompleted injection wells shall be equipped with tubing and packer upon completion or recompletion.~~

Exceptions may be made when there is:

~~—(1) No evidence of freshwater bearing strata.~~

~~(1)~~ (2) More than one string of casing cemented below the base of fresh water.

~~(2)~~ (3) Other justification, as determined by the district deputy, based on documented evidence that ~~freshwater~~ USDW and oil zones can be protected without the use of tubing and packer.

(h) Data shall be maintained to show performance of the project and to establish that no damage to life, health, property, or natural resources is occurring by reason of the project. ~~Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons, or upon written notice from the Division.~~ Project data shall be available for periodic inspection by Division personnel.

(i) Maximum allowable surface pressure shall equal top perforation depth, in true vertical depth, multiplied by the difference between the injection gradient and the injectate fluid gradient ( $MASP = (IG - IFG) * TVD$ ). The injection gradient used for this calculation shall be 0.95 multiplied by the fracture gradient as determined under Section 1724.7(a)(4). The Division may approve a higher maximum allowable surface injection pressure based on a conclusive demonstration by the operator that the injected fluid will remain confined to the intended zone of injection.

~~To determine the maximum allowable surface injection pressure, a step-rate test shall be conducted prior to sustained liquid injection. Test pressure shall be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate district office shall be notified prior to conducting the test so that it may be witnessed by a Division inspector. The district deputy may waive or modify the requirement for a step-rate test if he or she determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.~~

(j) A mechanical integrity test (MIT) must be performed on all injection wells to ensure the injected fluid is confined to the approved zone or zones. An MIT shall consist of a two-part demonstration as provided in ~~subsections subdivisions~~ (j)(1) and (2).

(1) Prior to commencing injection operations, each injection well must pass a pressure test of the casing-tubing annulus to determine the absence of leaks. Thereafter, the ~~annulus of casing of~~ each well must be tested at least once every five years; ~~prior to recommencing injection operations following the repositioning or replacement of downhole equipment;~~ or whenever requested by the appropriate Division district deputy. The casing shall be tested to the maximum allowable surface pressure, or 200 psi, whichever is greater. With approval from the Division, casing may be tested at a lower pressure, provided that there is a corresponding reduction of the maximum allowable surface pressure for the injection well. Pressure testing is required even if the well is no longer an active injection well, unless the well is no longer approved for injection and it is producing oil or gas.

~~(2) When required by subsection (j) above, injection wells shall pass a second demonstration of mechanical integrity.~~ The second test of a two-part MIT shall demonstrate that there is no fluid migration behind the casing, tubing, or packer. This may be done by temperature survey, radioactive tracer, or noise log performed in accordance with Section 1724.10.1, or other method approved by the Division.

~~—(3) The second part of the MIT must be performed within three (3) months after injection has commenced. Thereafter, water disposal injection wells shall be tested at least once each year, or on a testing schedule approved by the Division based upon consideration of the age of the well, geology, and operational factors; waterflood wells shall be tested at least once every two years; and steamflood wells shall be tested at least once every five years. Such testing for mechanical integrity shall also be performed following any significant anomalous rate or pressure change, or whenever requested by the Division. The second part of the MIT is not required if the injection well is inactive, but shall be performed within three months after recommencing injection. The second part of the MIT is not required for a cyclic steam well that has never injected more than 100 gallons per foot.~~ appropriate Division district deputy. The MIT schedule may be modified by the district deputy if supported by evidence documenting good cause.

(3) All anomalies encountered during either part of the required MIT shall be reported and explained to the Division.

(4) The appropriate district office shall be notified at least 48 hours before performing either part of the MIT required under this subdivision so that Division staff ~~before such tests/surveys are made, as a Division inspector~~ may witness the operations. Copies of surveys and test results shall be submitted electronically to the Division within 60 days.

(k) Injection wells and related facilities shall be continually monitored in order to allow for the discovery and correction of abnormal operating conditions, as follows:

(1) Wellheads, well safety systems, well piping and site locations shall be inspected for operability, leaks and mechanical or other faults.

(2) Wellhead injection pressure and injection flow rate shall be monitored for unexpected changes indicative of a mechanical fault.

(3) Monitoring well pressures or fluid levels shall be monitored for unexpected changes indicative of mechanical fault.

(4) Well annulus pressures or vents shall be monitored.

(l) The operator shall cease injection into an injection well and shall not resume injection into the well without subsequent approval from the Division if any of the following occur:

(1) Mechanical integrity testing required under subdivision (j) has not been performed on the well, or notification and results required under subdivision (j)(4) have not been provided to the Division;

(2) The well failed a mechanical integrity, or there is any other indication that the well lacks mechanical integrity;

(3) There is any indication that fluids being injected into the well are not confined to the intended zone of injection;

(4) There is any indication of that damage to life, health, property, or natural resources, or loss of hydrocarbons is occurring by reason of the project;

(5) The operator did not provide information regarding the well as required under Public Resources Code section 3227;

(6) The well has been inactive for more than two years; or

(7) The Division instructs the operator in writing to suspend injection.

(m) (k)-Additional requirements or modifications of the above requirements may be necessary to fit specific circumstances and types of projects. Examples of such additional requirements or modifications are:

(1) Injectivity tests.

(2) Graphs of time vs. oil, water, and gas production rates, maintained for each pool in the project and available for periodic inspection by Division personnel.

(3) Graphs of time vs. tubing pressure, casing pressure, and injection rate maintained for each injection well and available for periodic inspection by Division personnel.

(4) List of all observation wells used to monitor the project, indicating what parameter each well is monitoring (i.e., pressure, temperature, etc.), submitted to the Division annually.

(5) List of all injection-withdrawal wells in a gas storage project, showing casing-integrity test methods and dates, the types of safety valves used, submitted to the Division annually.

(6) Isobaric maps of the injection zone, submitted to the Division annually.

(7) Notification of any change in waste disposal methods.

#### AUTHORITY:

Note: Authority cited: Section 3013, Public Resources Code. Reference: Section 3106, Public Resources Code.

#### **1724.10.1. Mechanical Integrity Testing**

(a) In addition to all other applicable federal, state, and local requirements, a radioactive tracer performed under Section 1724.10(j)(2) shall adhere to the following:

(1) Testing must be conducted while injecting, and the operator shall ensure that adequate water can be supplied for the test. The injection rate shall be governed by the ability of the operator to track the radioactive tracer as it moves downward, but the injection rate should be as close to the maximum injection rate as practical.

(2) There shall be an adequate pressure differential across the tubing wall in order for the for the test method to be valid.

(3) The casing valve must be opened during testing and there must be no fluid flow. If fluid flow continues from the casing valve, the casing-tubing annulus shall be evaluated.

(4) Gamma ray detector sensitivity shall be set so that lithologic effects are just identifiable.

(5) A background gamma ray log over the interval to be tested shall be recorded before any radioactive material is introduced into the well.

(6) The test shall record measurements over a period of three to five minutes with the tool stationary at two points which are representative of the extremes of natural radiation within the interval to be tested.



(7) The release of a slug of radioactive material must be above the interval to be tested.

(8) The slug of radioactive material shall be followed with the logging tool or make repeated passes upward through the slug as it moves down the well. All logging shall be done at a single logging speed which is appropriate for the injection rate to allow quantitative measurements of deflections to be evaluated.

(9) If repeated passes are used, the logs resulting from the slug-tracking exercise should overlap so that the return of radioactivity to the level which existed before the slug's passing is demonstrated for the entire length of the section of the well being tested. The logs of all passes should be presented as a composite log on a common depth track. If means to differentiate the log traces are available no other presentation is required. If the traces cannot be differentiated on the composite log, they should also be presented individually.

(10) After any ejection, the slug of radioactive material must be followed until it has moved below the interval being tested. If the slug splits, both slug portions must be accounted for.

(11) After completion of the passes, a final log should be made through the entire tested interval to check for residual radioactivity which might be associated with exit of tracer material from the well bore.

(12) If a well is injecting at a rate that creates a fluid velocity greater than one foot per second, radioactively treated beads shall be introduced into the well and evaluated according to parts 8 through 11 above.

(13) Steam injection wells shall be tested using an inert gas tracer.

(b) A temperature log performed under Section 1724.10(j)(2) shall adhere to the following:

(1) The well must be taken off injection at least 24 hours but not more than 48 hours prior to performing the temperature log, unless an alternate duration has been approved by the Division.

(2) The logging tool shall be calibrated to the extent feasible.

(3) The well must be logged from the surface downward, lowering the tool at a rate of no more than 30 feet per minute.

(4) If the well has not been taken off injection for at least 24 hours before the log is run, comparison with either a second log run six hours after the time the log of record is started or a log from another well at the same site showing no anomalies shall be available to demonstrate normal patterns of temperature change.



(5) The log data shall be provided to the Division electronically in either LAS or ASCII format.

(c) A noise log performed under Section 1724.10(j)(2) shall adhere to the following:

(1) Noise logging may be carried out while injection is occurring.

(2) Noise measurements must be taken at intervals of 100 feet to create a log on a coarse grid.

(3) If any anomalies are evident on the coarse log, there must be a construction of a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

(4) Noise measurements must be taken at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

(A) The base of the lowermost bleed-off zone above the injection interval;

(B) The base of the lowermost USDW; and

(C) In the case of varying water quality within the zone of USDW, the top and base of each interval with significantly different water quality from the next interval.

(5) Additional measurements must be made to pinpoint depths at which noise is produced.

(6) A vertical scale of 1 or 2 inches per 100 feet shall be used.

#### **AUTHORITY:**

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

#### **1724.11. Incident Response**

(a) For the purposes of this section, "reportable incident" means any of the following:

(1) A mechanical integrity test indicates that an injection well lacks integrity or is otherwise incapable of performing as approved by the Division;

(2) A failure, breach, or hole in the well tubing or packer;

(4) A failure, breach, or hole in the well casing, including failures above and below a packer;

(5) The migration or movement of any amount of injection fluid to an unpermitted zone; or

(6) Any other incident or occurrence that indicates fluid is not or may not be confined to the approved injection zone, or that indicates the injection well threatens human health, public safety or the environment.

(b) In the event of a reportable incident, the operator of the well must notify the appropriate district office immediately upon discovering the reportable incident. The operator shall consult and share information with the Division.

(c) The operator shall comply with all operational and remedial directives of the Division, including but not limited to ceasing injection operations at the well(s) in question.

AUTHORITY:

Note: Authority cited: Sections 3013 and 3106, Public Resources Code. Reference: Section 3106, Public Resources Code.

**Comments on Draft Regulations to DOGGR's UIC Program**  
(BWH 2-16-16)

General:

1. Existing regulations are already beyond sufficient, and well into superfluously intrusive territory.
2. Most UIC program failures on record can be traced to a failure by DOGGR to adequately enforce existing regulations, or a failure by DOGGR to detect, with the resources and surveillance systems they already possess, a violation of existing regulations. How many of those that don't fall into this category would have been prevented by the proposed changes? I don't know, and I suspect no one else does either. But I suspect that number is close to zero.
3. The proposed modifications represent a severe additional burden on private industry in aid of nothing. It is friction - non technical persons reading this are advised to look up the technical definition of friction. They are an illegal and immoral, "take" of skills and labor for which my industry receives no just compensation.
4. The blatant hypocrisy of a government agency imposing this burden on an industry that receives an order of magnitude *less* compensation per unit for producing the product than the State and Feds *each* get for regulating it is mind shattering. Any DOGGR employee with a scintilla of integrity would immediately resign his post, had they not already been purged from the ranks by years of the Brown stained regime.

1724.6.c

"...Approval of an underground injection project is at the Division's ongoing discretion and a Project Approval Letter is subject to suspension, modification, or rescission by the Division". The Division's proposal to reserve the right to unilaterally modify project provisions, without discussion or negotiation, at any time is immoral and tyrannical.

1724.6.e:

What kind of idiots does the Division think Operators are? We work for Private Industry rather than for the DOGGR; which exerts competitive pressures that assure a level of competence not enjoyed by protected government employees.

1724.7:

I find it ironic that 99% of the data required by this section consists of spoon feeding back to the Division data that is already available in the Division's web site. But I suppose the intent is to ensure that the Operator has actually examined the data, and done an engineering and geological review. One would like to presume the Division would do the same for themselves before issuing a permit.

1724.7.a.1.E.i-ii:

Seems like this should be the Division's job to do before issuing a permit. But the entire thrust of regulations these days seems to be getting private industry to do the Division's job for them.

1724.7.a.1.I.4:

Requiring a SRT of each injection well is horribly wasteful, redundant, expensive and mind-bogglingly stupid. What kind of idiots think up this crap?

1724.7.a.1.I.8:

More CYA BS clearly designed to shield apparatchiks from any responsibility for any problems that might occur, while simultaneously giving them a tool to avoid approving any project they don't like for any reason, or for no reason at all. You miserable punks are stacking the deck as ice-cold in your favor as you can, without regard for justice, fairness, or due process.

1724.7.a.1.I.8c:

Why is this additional burden necessary? In aid of what, exactly? Division convenience, at the expense of the industry they parasite seems to be the only logical answer.

1724.7.1:

Are you kidding me? A casing diagram, with a flat data set, to the proposed specifications would be so excessively data packed as to be illegible. I'm mildly surprised that you little tyrants didn't dictate what font/size to use, and what color to use to present specific types of information. What Epic Tools you are.

- It is stupid and redundant to require BFW & BUSDW on each diagram. This data is captured ad nauseam elsewhere, and the lazy little scuts reviewing the project could at least bestir themselves to LOOK there for it.
- J; "Method of determining" is odious BS. If the guy reading the schematic doesn't know, he has no business being on the payroll. I didn't spend years mastering my trade to be forced to spoon feed spoiled little apparatchiks.
- N, O, and P are ridiculous. But then this entire document mostly is.
- P.2 & 3? Seriously? Can't wait to see what that's gonna look like!
- I'd LOVE to see one of you Division weenies actually draw a schematic of a deviated, highly remediated well to these specs. Keep track of how many useless hours you spend on it, and then submit it blind to another apparatchik (who doesn't know it was done in-house) and watch him enthusiastically reject it.

1724.7.2:

The price of lab work just went up by an order of magnitude, to no good purpose.

1724.7.3:

This is the most expensive, poorly designed, and inefficient SRT that I've ever encountered. Someone needs to go back to engineering school. All of you need to go back to governance school, where rule one is to not over-regulate and over-specify procedure; doing so stifles operational, technical, and scientific progress and innovation. But hey, maybe that's the point of this steaming mess.

1724.10.j.(1):

"Pressure testing is required even if the well is no longer an active injection well, unless the well is no longer approved for injection and it is producing oil or gas." Why? In aid of what?

1724.10.j.(4):

48 hours? Really? Why not 148 hours? 24 hours not enough anymore? Too many missed hair/nail appointments?

1724.10.1:

Over-the-top unnecessarily restrictive. See comments on 1724.7.3 above, as they also apply here.